Q. Please state your name, business address and position with PacifiCorp dba Rocky Mountain Power ("Company").

A. My name is Chad A. Teply. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah. My position is vice president of resource development and construction for PacifiCorp Energy. I report to the president of PacifiCorp Energy. Both Rocky Mountain Power and PacifiCorp Energy are divisions of PacifiCorp.

Qualifications

Q. Please describe your education and business experience.

A. I have a Bachelor of Science Degree in Mechanical Engineering from South Dakota State University. I am a Registered Professional Engineer in the state of Iowa. I joined MidAmerican Energy Company in November 1999 and held positions of increasing responsibility within the generation organization, including the role of project manager for the 790-megawatt Walter Scott Energy Center Unit 4 completed in June 2007. In April 2008, I moved to Northern Natural Gas Company as senior director of engineering. In February 2009, I joined the PacifiCorp team as vice president of resource development and construction, at PacifiCorp Energy. In my current role, I have responsibility for development and execution of major resource additions and major environmental projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission and parties with information supporting the prudence of capital investments in pollution control equipment, generation plant, and hydro projects being placed in service during the test period. My testimony also supports the prudence of incremental generation operations and maintenance costs associated with certain new resources, new pollution control equipment, and other generation fleet operational changes impacting this case.

Background

Q. Please provide a general description of the pollution control equipment and additional capital investments being placed in service, and the benefits gained from the investments.

A. The pollution control equipment investments included in this case primarily result in the reduction of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_X"), mercury ("Hg"), and particulate matter ("PM") emissions from the retrofitted facilities. These investments are required to comply with current, proposed, and probable environmental regulations. These investments constitute approximately 60 percent of the generation related capital investments placed in service or projected to be placed in service between July 2010 and June 2012, excluding the Dunlap I wind energy project which was included and approved in the major plant addition case, Docket no. 10-035-89.

Hydro generation plant investments, which constitute approximately 10 percent of the generation related capital investments placed in service or projected to be placed in service between July 2010 and June 2012, excluding Dunlap I, are primarily new license implementation measures required by the Federal Energy Regulatory Commission to allow continued operation of these low-cost generation assets.

Generation plant turbine upgrade investments enhance the Company's overall generation capability and cycle efficiency without increasing emissions for the large thermal units that receive this equipment.

Other generation plant investments support asset safety, reliability, and cost effectiveness via reduced risk of equipment and component failures, enhanced control systems, and improved security provisions.

Justification of Pollution Control Investment

Q. Why has the Company invested in pollution control equipment?

A. Through the 1977 amendments to the Clean Air Act, Congress set a national goal for visibility to remedy impairment from manmade emissions in designated national parks and wilderness areas; this goal resulted in development of the Regional Haze Rules, adopted in 2005 by the U.S. Environmental Protection Agency ("EPA"). The first phase of these rules trigger Best Available Retrofit Technology ("BART") reviews for all coal-fired generation facilities built between 1962 and 1977 that emit at least 250 tons of visibility-impairing pollution per year. Visibility-impairing pollutants include sulfur dioxide SO_2, nitrogen oxides NO_x and particulate matter PM. The Company has 14 units that meet the construction and emissions threshold criteria and are, therefore, "BART-eligible units." Pursuant to federal regulations at 40 CFR 51.308(e)(1)(ii), each state is required to determine which BART-eligible sources are also "subject to BART." BART-eligible sources are subject to BART if they emit any air pollutant that may reasonably be anticipated to cause or contribute to impairment of visibility in any designated national park or wilderness area. The investments in pollution control equipment are at the Company's BART-eligible units that have been determined by the state environmental regulators to be necessary after considering available technology; costs of compliance; energy and non-air quality environmental impacts; existing control equipment and the remaining useful life of the facility; and the degree of improvement in visibility reasonably anticipated to result from the use of such technology.

After considering these five factors, the respective state departments of environmental quality for the units made their BART determinations and incorporated the results of the above mentioned BART analyses into the operating permits, construction permits and Approval Orders (defined below) for the pollution control equipment contemplated by this case.

With respect to the Naughton Unit 2 low NO_X burners installation project and Wyodak low NO_X burners and bag house installation projects described below, the Wyoming Department of Environmental Quality ("WY DEQ") issued BART permits for those units on December 31, 2009, incorporating the equipment and installation schedules recommended via the BART review and contemplated in this case. The conditions of the BART permits are currently in the process of being incorporated into the Wyoming State Implementation Plan ("SIP") for Regional Haze in support of its goals to reduce visibility impairing emissions. The Wyoming SIP is subject to U.S. EPA review and approval. The WYDEQ has also issued construction permits for the Jim Bridger, Naughton, and Wyodak pollution control projects described below.

With respect to the Hunter Unit 2 and Huntington Unit 1 projects described below, the Utah Department of Environmental Quality ("UT DEQ") has incorporated the results of BART reviews completed for those facilities into the Utah SIP. The Utah SIP is subject to U.S. EPA review and approval. The state of Utah has also issued Approval Orders (*i.e.*, permits to construct) for each of the Hunter and Huntington pollution control projects described below.

In addition to the BART requirements under the regional haze rule, increasingly more stringent National Ambient Air Quality Standards have been and are being adopted for criteria pollutants, including SO_2, NO_2, ozone, and PM. Implementation of the pollution control projects described herein assists in meeting these more stringent standards, avoiding the negative consequences of an area being declared to be a nonattainment area. Further, while the Clean Air Mercury Rule, which would have required a reduction of mercury emissions of approximately 70 percent by 2018 was overturned by the United States Court of Appeals for the District of Columbia Circuit in February 2008, the U.S. EPA plans to propose a new rule that will require coal-fired generating facilities to reduce mercury, and potentially other emissions of hazardous air pollutants, through a Maximum Achievable Control Technology standard. Under a consent decree, the U.S. EPA must issue a proposed rule to regulate mercury emissions by March 2011 and a final rule no later than November 2011; compliance with the mercury standards would be required by November 2014. The bag house and scrubber projects described herein will assist in meeting the forthcoming Maximum Achievable Control Technology requirements.

In short, the pollution control investments contemplated in this case are required to maintain compliance with the environmental requirements described above.

Q. Please clarify the definition of a "presumptive BART emission limit" as it pertains to established federal pollution control standards.

A. The use of the term "presumptive BART emission limit" in the instance cited does not mean that BART emission limits are uncertain future requirements. Instead, the use of the term refers to emission rates identified in the Regional Haze Rule, Code of Federal Regulations (CFR), Title 40, Sections 51.300 through 51.309, and Appendix Y. Electronic copies of the referenced CFRs can be found at the following link:

http://www.access.gpo.gov/nara/cfr/waisidx_09/40cfr51_09.html

Presumptive BART emission limits come from Appendix Y cited above, and are rates defined by the EPA. States use the rates defined by the EPA to assist in determining whether a BART-eligible facility is presumed to meet the requirement to install best available retrofit technology. For example, if the installation of low-NOx burners on a BART-eligible facility with cell-burners firing sub-bituminous coal achieves an emission rate of 0.28 lb/MMBtu, which is below the U.S. EPA presumptive BART rate of 0.45 lb/mmBtu (the presumptive rate for a cell-burner unit burning sub-bituminous coal), it can be presumed that the installation of low-NO_x burners on this unit meets federal best available retrofit requirements with respect to NO_x control, and no additional controls would be likely to be required. With respect to SO_2 control, the states of Utah and

Wyoming, along with New Mexico, are participating in a market-trading program identified in the Regional Haze Rule, CFR, Title 40, Section 51.309. Under this program the states have set SO_2 emission reduction milestones that must be achieved. These milestones have been developed assuming that each coal-fired generating unit meets the lower of its historic emission rate or the presumptive SO_2 rate. The EPA has defined the presumptive SO_2 emissions rate as 0.15 lb/mmBtu or 90 percent removal. Here again, if the installation of pollution control equipment on a BART-eligible facility achieves an emission rate less than that presumptive limit and overall emission reduction goals are being met, it can be presumed that the installation meets federal best available retrofit requirements and no additional controls will be required.

Q. What factors does the Company consider when determining which capital investments to make in environmental equipment retrofit projects?

A. As an initial matter, the Company assesses its environmental compliance obligations and the timing of those compliance obligations; in that context, the Company assesses the overall cost and availability of various control technologies and alternatives. As the Company considers when, whether and what capital investments to make in environmental controls, it takes several additional factors into consideration, including: evaluation of current state and federal environmental regulatory requirements; review of emerging environmental regulations and rulemaking; and whether alternate compliance options exist, such as purchasing allowances, that may result in lower costs to comply. As part of the BART review of each facility, the Company evaluated several technologies on their ability to economically achieve compliance and support an integrated approach to control criteria pollutants (*e.g.* SO_2, NO_X, and PM for the facility), if it were to continue to operate and to burn coal. The BART analyses reviewed available retrofit emission control technologies and their associated performance and cost metrics. Each of the technologies was reviewed against its ability to meet a presumptive BART emission limit based on technology and fuel characteristics. The BART analyses outlined the available emission control technologies, the cost for each and the projected improvement in visibility which can be expected by the installation of the respective technology. For each unit or source subject to BART, the state environmental regulatory agencies identify the appropriate control technology to achieve what the air quality regulators determine are cost-effective emission reductions. Once the appropriate BART technology was identified, the Company moved forward with its competitive bidding process to evaluate and ultimately select the preferred provider for the projects.

Q. What process is in place to explore ongoing investment versus retirement of the Company's coal units?

A. The existing integrated resource planning ("IRP") proceedings conducted in all six of the states served by the Company provides the process to address ongoing investment versus retirement of the Company's coal units. Future IRP proceedings will increasingly focus upon the complexity in balancing factors such as:

(1) pending environmental regulations and requirements to reduce emissions in addition to addressing waste disposal and water quality concerns,

(2) avoidance of excessive reliance on any one generation technology,

(3) costs and trade-offs of various resource options including energy efficiency, demand response programs, and renewable generation,

(4) state-specific energy policies, resource preferences, and economic development efforts,

(5) additional transmission investment to reduce power costs and increase efficiency and reliability of the integrated transmission system, and

(6) maintaining rates as affordable as possible.

Q. Is the Company obligated to install pollution controls required by state permits, regardless of whether final U.S. Environmental Protection Agency review and approval of the respective regional haze state implementation plans remains pending?

A. Yes. The BART permits and construction permits issued by the respective state agencies for the pollution control investments contemplated in this case include stand-alone requirements enforceable by the laws of the respective states. These requirements are enforceable independent of whether EPA has approved the respective state implementation plans.

Q. Does the Company anticipate that final U.S. Environmental Protection Agency approval of the respective state implementation plans will require alternate pollution control equipment to be installed, making the equipment contemplated in this case obsolete?

A. No. While it is possible that the EPA will require more stringent emission limits to be achieved, the pollution control technology selections completed to date apply best available retrofit technology, comply with existing state and federal regulations, and support Regional Haze Rule objectives. The Company also incorporates into its pollution control equipment contract specifications design considerations intended to provide appropriate levels of operating margin, equipment redundancy, and system maintainability and reliability provisions to support an expected range of process inputs, operating conditions, and system performance. Although the Company cannot predict future pollution control regulations and associated emissions limits, the Company does take steps to procure a prudent level of design flexibility to accommodate potential changes in system performance requirements, where practical.

Q. Does the Company anticipate that final U.S. Environmental Protection Agency approval of the respective state implementation plans will require additional pollution control equipment to be installed on the facilities contemplated in this case?

A. That is a possibility; however, the pollution control equipment investments contemplated in this proceeding would be required in any event. Should the EPA require additional emissions reductions, the incremental reductions would likely be accomplished via additional projects that build on or enhance the capabilities of installed pollution control projects, otherwise act independently of installed pollution control projects, or via facility operating changes. The Company includes the following considerations in its planning efforts in order to best meet the Company's future emissions reductions obligations: facility operations compliance options, available control technologies, cost of compliance; proposed compliance deadlines, and emerging environmental regulations and rulemaking.

Q. Would the Company's decision to make these incremental investments in environmental controls at these units change if limitations were placed on carbon dioxide emissions, such as in the Waxman-Markey bill in the U.S. House of Representatives or the Kerry-Lieberman bill in the U.S. Senate?

A. No. The Company is engaged in assessing its existing generation resources, its planned supply and demand-side resources and its 10-year capital budget with respect to the impact of potential carbon dioxide emissions restrictions. While other planned investments may change, the Company's plans regarding the emission control investments included in this case would not change as a result of carbon-emission restrictions. The current controls are required under existing regulations and the units have depreciation lives for ratemaking purposes that provide sufficient remaining time to depreciate the investments in the environmental controls. While carbon restrictions may ultimately affect the cost of generating electricity at these units, they are still anticipated to be utilized as part of the company's overall generating fleet that will be necessary to provide baseload electricity at a reasonable cost to customers.

Q. What efforts are being taken by the Company to understand and evaluate impacts of potential future environmental regulations on the Company's business?

A. PacifiCorp and its parent, MidAmerican Energy Holdings Company, are very active in the current Congressional, state legislative, and EPA activities regarding environmental controls affecting virtually all emissions from coal and natural gas generating units, as well as other environmental issues. The Company is very cognizant that some potential restrictions on greenhouse gas emissions ("GHGs") could require coal (and potentially natural gas) units to adjust the depreciation lives for ratemaking purposes. The Company considers this possibility when determining whether to proceed with investments to control emissions other than GHGs.

PacifiCorp has been a participant in the Oregon regulatory proceedings regarding the potential early closure or installation of emission controls at Portland General Electric's Boardman plant. PacifiCorp and its parent are also closely following similar proceedings in Colorado in which regulated utilities are required to comply with a statute enacted in 2010. That statute primarily focused on reductions in nitrogen oxides and facilitated the conversion of 1000 MW of coal-fired generation to natural gas generation in that state. While the Boardman proceeding has largely been concluded by the state agencies, Oregon's state implementation plan that incorporates requirements leading up to an early closure of the Boardman facility is still subject to approval by the EPA. The regulatory proceedings in Colorado are still pending.

Q. Is the Company undertaking reasonable efforts to ensure that environmental regulators consider the uncertainty created by requiring investments in certain emissions controls prior to knowing the nature and extent of controls on other emissions?

A. Yes. The Company filed an appeal of the Regional Haze requirements in Wyoming for this exact reason. Wyoming was the first state to make the determination that BART required the installation of selective catalytic reduction (SCR) controls for nitrogen oxides. The Company disagreed with that determination and asserted that Appendix Y of 40 CFR Part 51 did not contemplate the installation of post-combustion controls. Additionally, the Company was concerned that other environmental laws and/or regulations could impact the Company's facilities affected by Wyoming's BART determinations in a way that that impacted the economic analysis associated with the installation of the contemplated controls. These requirements not only include greenhouse gas reduction requirements, but also a host of regulatory initiatives underway by the U.S. EPA, including the outcome of pending coal combustion waste disposal regulations and maximum achievable control technology (MACT) standards for mercury and non-mercury hazardous air pollutants. Due to the uncertainty associated with the potential impact of these rules on the Company's facilities, the Company appealed the BART permits issued by the Wyoming Department of Environmental Quality to ensure that these and other issues were considered in the agency's decision and, to the extent these issues had an impact on long-term viability of the facilities, the economic analysis of adding emission reduction equipment was properly reflected. Since the time that the Company filed its appeal, the U.S. EPA issued a BART determination for the Four Corners Power Plant in Arizona, requiring the installation of SCR at all five units operated by Arizona Public Service within a five-year period, without regard to other environmental requirements or their associated uncertainties. Likewise, the U.S. EPA recently proposed to require the installation of four SCR within three years at the San Juan Generating Station in New Mexico.

In November 2010, PacifiCorp settled the Wyoming BART appeal to resolve the matter in a way that did not require more controls and impose additional costs earlier than originally proposed in the Department of Environmental Quality's BART determinations. To provide maximum flexibility in the event that other environmental requirements or uncertainties arose, PacifiCorp and the Wyoming Department of Environmental Quality included terms in the settlement agreement to address a modification if future changes in either federal or state requirements or technology would materially alter the emissions controls and rates that would otherwise be required.

Q. Did the Company provide the Wyoming Department of Environmental Quality additional information regarding the Company's overall emission reduction plans through 2023 in connection with the settlement discussed above?

A. Yes. The Company provided additional information including an overview of the Company's long-term emission reduction commitment, project installation schedules and compliance deadlines, emission reduction priorities, anticipated customer impacts, and brief descriptions of other environmental initiatives that are also expected to impact future operating costs of the Company. A copy of this additional information is provided for reference in Exhibit RMP___(CAT-1).

Timing of Investment

Q. Why is PacifiCorp installing pollution control equipment at this time?

A. As discussed above, the Company is installing pollution control equipment at this time to comply with the Regional Haze Rules, as well as in response to more stringent National Ambient Air Quality Standards, the impending mercury requirements, and a number of existing and emerging emission reduction requirements. Final installation activities and tie-in of the pollution control equipment described above can only be accomplished when the units are off-line. Meeting the timing requirements of construction permits and Approval Orders and reducing plant outage time necessitated completion of final installation activities and tie-in of the pollution control equipment during the scheduled overhauls within this test period. Installation of the pollution control equipment and associated systems included in this case represent a significant step for PacifiCorp's coal-fueled power plant fleet toward meeting the SO_2 and NO_X reductions required by the Regional Haze Rules and established by the respective states' emissions reduction milestones.

Customer Considerations

Q. What are the benefits to customers of installing the pollution control equipment and why should Utah customers pay the costs related to this project?

A. Customers directly benefit from the continued availability of low-cost generation produced at the facilities while also achieving environmental improvements from these resources, resulting in cleaner air. In addition, the tie-in of these necessary controls is being accomplished during planned maintenance outages, as opposed to scheduling separate outages for this work, which reduces replacement power costs. The Company has ten BART-eligible units in Wyoming and four in Utah. The BART controls for each of these units must be installed as expeditiously as possible, but no later than five years from the date the respective SIPs are approved and prior to the compliance dates specified in the permits Postponing installation of the pollution control equipment included in this case to later planned maintenance outages would make it virtually impossible for the Company to effectively ensure that all of its affected units meet compliance deadlines and would place the Company at risk of not having access to necessary capital, materials, and labor while attempting to perform these major equipment installations in a compressed timeframe. As the deadlines for environmental requirements across the country draw closer, the demand for equipment and skilled labor is likely to increase, making timely compliance more difficult without incurring significant additional cost.

Description of Pollution Control Investment Projects

Q. Please describe the Naughton Unit 2 scrubber addition project and associated equipment.

A. The scrubber addition project at the Naughton Unit 2 power plant includes the installation of sulfur dioxide controls. The capital investment for the project being placed in service during the test period is approximately $157 million. Construction began in 2010, and the project is expected to be placed in service by November 2011. The new pollution control equipment will be tied into the existing unit during a scheduled plant maintenance outage. The project will install a flue gas desulfurization ("FGD") system. The FGD system injects reagent slurry containing sodium carbonate and sodium bicarbonate in the top of an absorber vessel (scrubber) with a network of spray nozzles. The distribution of spray nozzles and trays causes the sodium carbonate slurry to intermix with the flue gas passing through the absorber vessel. The SO_2 in the flue gas reacts with the sodium carbonate in the slurry to form a waste slurry of sodium sulfite and sodium sulfate. The liquid waste slurry is then captured and transported to a scrubber waste pond for disposal. The scrubber waste will ultimately be dewatered and retained in a closed and capped scrubber waste cell on the Naughton plant site.

Other equipment to be installed as part of the project includes induced draft fans, boiler reinforcement, new ductwork and a new chimney, sodium carbonate slurry reagent preparation systems, waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

Q. Is the Company also installing scrubber facilities at the Naughton Unit 1 power plant?

A. Yes. The Naughton Unit 1 scrubber project is being constructed concurrently with the Naughton Unit 2 scrubber project, but on a different schedule. The description of the Naughton Unit 1 scrubber project is for the most part identical to that provided above.

Q. Will the Naughton Unit 1 scrubber addition project also be placed in service during the test period used in this case?

A. Yes. The Naughton Unit 1 scrubber addition project is expected to be placed in service during the next planned major maintenance outage for that unit. The capital investment for the project being placed in service during the test period is approximately $120 million. The project is expected to be complete by May 2012. The planned major maintenance outages for the Company's generation assets are scheduled on a control area basis, considering optimal frequency between overhauls and to minimize the number of major units off line at any one time. The Company completed its most recent overhaul to Naughton Unit 1 in 2008 and is scheduled for its next overhaul in the spring of 2012. The Company's intent in establishing the tie-in schedules for the Naughton Unit 1 and Naughton Unit 2 pollution control equipment was to balance the aggregated construction costs and schedules for the pollution control equipment projects against the established planned maintenance overhaul schedules, work plans, and budgets for the respective units.

Q. Are common facilities costs associated with the Naughton Unit 1 and Naughton Unit 2 scrubber addition projects included in this case?

A. Yes. The cost of all common facilities that are required to be placed in service to allow prudent operation of either unit's new emission control equipment are incorporated into the Naughton Unit 2 capital investment being placed in service by November 2011. Common facilities include reagent preparation, waste disposal, electrical supply, and ancillary utility systems, as well as site preparation and the chimney.

Q. Please describe the Wyodak power plant stand-alone bag house project and associated equipment.

A. A stand-alone bag house will be installed at the Wyodak power plant for control of PM, SO_2, and Hg emissions consistent with requirements. In order to increase the SO_2 removal efficiency of the unit above 90 percent as required to comply with environmental requirements, a bag house must be utilized in conjunction with the existing dry spray dryer absorbers ("SDAs"). Without a bag house, the best SO_2 removal efficiency an SDA on the unit can achieve with Wyodak coal is between 70 and 80 percent. Adding the bag house is necessary to achieve the permitted SO_2 removal requirements.

The PacifiCorp share of the capital investment for the Wyodak bag house project being placed in service during the test period is approximately $103 million. Construction began in 2010, and the project is expected to be placed in service by April 2011. The new pollution control equipment will be tied into the existing unit during a scheduled plant maintenance outage.

The bag house will capture particulate matter from the flue gas stream as it passes through the bag house and will improve the unit's efficiency in removing SO_2 and Hg from the flue gas. The dry particulate waste stream containing both fly ash and scrubber waste will then be transported to an ash collection pond on adjacent coal mine property for disposal by the mine operator.

Other equipment to be installed as part of the project includes induced draft fans, boiler reinforcement, new ductwork, waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

Q. Please describe the Dave Johnston Unit 4 pollution control project and associated equipment.

A. The pollution control project being undertaken at the Dave Johnston Unit 4 power plant will upgrade and improve the unit's particulate matter controls to comply with environmental requirements and will also install required SO_2 controls. The capital expenditure for the project during the test period is approximately $101 million.

Construction began in 2008, and the project is expected to be operational by April 2012. The new equipment will be tied into the existing equipment during a scheduled plant maintenance outage. The project will install a dry flue gas desulfurization ("DFGD") system and a fabric filter bag house. A DFGD system injects lime slurry in the top of an absorber vessel (scrubber) with a rapidly rotating atomizer wheel. The rapid rotation of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas. The SO_2 in the flue gas reacts with the calcium in the lime slurry to form calcium sulfate in the form of particulate matter. The dry particulate matter is then captured in the downstream bag house along with fly ash from the boiler. The DFGD system will produce a nonhazardous dry waste product suitable for landfill disposal.

Other equipment to be installed as part of the project includes induced draft fans, boiler reinforcement, new ductwork, lime slurry reagent preparation systems, waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

Q. Has the Company also installed scrubber and associated facilities at the Dave Johnston Unit 3?

A. Yes. The Company placed a scrubber and associated facilities at the Dave Johnston Unit 3 power plant in service in May 2010. The majority of the costs associated with the Dave Johnston Unit 3 scrubber and all common facilities required to be placed in service to allow prudent operation of either unit's new emission control equipment were included in Utah Major Plant Addition Docket 10-035-13 filings by the Company. Approximately $9.5 million of additional investment associated with the Dave Johnston Unit 3 scrubber and associated facilities has been made subsequent to the project's in service date, which was not included in the major plant addition docket. That investment is included in this case. Common facilities include reagent preparation, waste disposal, electrical supply, and ancillary utility systems, as well as site preparation and the chimney.

Q. Please describe the Huntington Unit 1 power plant bag house conversion project, scrubber upgrade project, and associated equipment.

A. The bag house conversion project at the Huntington Unit 1 plant converted an existing electrostatic precipitator to a bag house for PM and Hg emissions control consistent with requirements described earlier in my testimony. The capital investment for the bag house conversion project being placed in service during the test period is approximately $93 million. Construction began in 2009, and the project was placed in service in November 2010. The bag house conversion was completed during a scheduled plant maintenance outage. The bag house will capture PM and help remove Hg from the flue gas stream as it passes through the bag house. The dry particulate waste stream is then transported to an on-site landfill for disposal.

Other equipment to be installed as part of the project includes upgraded scrubber booster fans, boiler reinforcement, new ductwork, modifications to the existing chimney to accommodate wet operation, relocation of the stack opacity monitors, scrubber waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

The scrubber project at the Huntington Unit 1 power plant is for required SO_2 controls for the unit and a new scrubber waste material handling system. The new waste handling equipment will be designed to manage the increase in waste product from the higher removal efficiency and increased throughput of the scrubber.

The capital investment for the scrubber upgrade and waste material handling project being placed in service during the test period is approximately $41 million. Construction began in 2010, and the scrubber upgrade portion of the project was placed in service in November 2010. The scrubber waste handling portion of the project is expected to be placed in service by March 2011. The scrubber equipment upgrade will be completed during a scheduled plant maintenance outage. Installation of the waste handling portion of the project will be completed with the plant in service.

The scrubber project includes installation of new pumps to increase the capacity of the slurry delivery system of the unit's existing flue gas desulfurization ("FGD") system,, effectively increasing the liquid (slurry) to flue gas ratio within the absorber vessels (scrubbers), and expanding waste material handling system capacity. The FGD system injects lime slurry in the top of a scrubber with a network of spray nozzles and trays. The distribution of spray nozzles and trays causes the lime slurry to intermix with the flue gas passing through the absorber vessel. The SO_2 in the flue gas reacts with the calcium in the slurry to form a waste slurry of calcium sulfite and calcium sulfate. The project will add oxidation air blowers to the system to ensure conversion of the calcium sulfite to calcium sulfate. Calcium sulfate is easier to dewater and the change will allow the slurry waste stream to be more effectively dewatered, and transported to a scrubber waste landfill for disposal.

Other equipment to be installed as part of the project includes waste material handling system hydroclones as a replacement for the existing thickener, vacuum drum filters, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

Q. Please describe the Hunter Unit 2 power plant bag house conversion project, scrubber upgrade project, and associated equipment.

A. The bag house conversion project at the Hunter Unit 2 power plant will convert an existing electrostatic precipitator to a bag house to meet PM and Hg emissions control requirements. The bag house will capture PM and help remove Hg from the flue gas stream as it passes through the bag house. The dry particulate waste stream is then transported to an on-site landfill for disposal. Other equipment to be installed as part of the project includes upgrading the scrubber booster fans, boiler reinforcement, new ductwork, modifications to the existing chimney to accommodate wet operation, relocation of the stack opacity monitors, waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

The PacifiCorp share of the capital investment for the bag house conversion project being placed in service during the test period is approximately $55 million. Construction began in 2010, and the project is expected to be placed in service by May 2011. The bag house conversion will be completed during a scheduled plant maintenance outage. The scrubber project at the Hunter Unit 2 power plant will install upgraded SO_2 controls for the unit and an improved scrubber waste material handling system to meet environmental requirements.

The scrubber project will upgrade the unit's existing FGD system by increasing the capacity of the slurry delivery system utilizing new pumps, effectively increasing the liquid (slurry) to flue gas ratio within the absorber vessels (scrubbers), and expanding waste material handling system capacity. The FGD system injects lime slurry in the top of a scrubber with a network of spray nozzles and trays. The distribution of spray nozzles and trays causes the lime slurry to intermix with the flue gas passing through the absorber vessel. The SO_2 in the flue gas reacts with the calcium in the slurry to form a slurry waste of calcium sulfite and calcium sulfate. The project will add oxidation air blowers to the system to ensure conversion of the calcium sulfite to calcium sulfate. Calcium sulfate is easier to dewater and the change will allow the slurry waste stream to be more effectively dewatered, and transported to a scrubber waste landfill for disposal.

The PacifiCorp share of the capital investment for the scrubber upgrade and material handling project being placed in service during the test period is approximately $34 million. Construction began in 2010, and the scrubber upgrade and the scrubber waste material handling portions of the project are expected to be completed by May 2011. The scrubber reagent preparation system upgrade portion of the project is expected to be placed in service by March 2012. The scrubber equipment upgrade will be completed during a scheduled plant maintenance outage. Installation of the reagent preparation system upgrade and the waste handling portion of the project will be completed while the plant is in service, and will not require an extended plant maintenance outage for tie-in.

Other equipment to be installed as part of the project includes lime slurry reagent preparation systems, waste material handling system hydroclones as a replacement for the existing thickener, vacuum drum filters, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems

Q. Please describe the Hunter Unit 1 power plant scrubber upgrade project and associated equipment.

A. The scrubber project at the Hunter Unit 1 power plant will install upgraded SO_2 controls for the unit and an improved scrubber waste material handling system to meet environmental requirements. The detailed description of the Hunter Unit 1 scrubber project is for the most part identical to that provided for Hunter Unit 2 above.

Costs associated with the capital investment for the scrubber upgrade and material handling portions of the project ARE NOT included in the revenue requirement in this case due to the projected in-service dates. Construction is scheduled to begin in 2012, and the scrubber upgrade portion of the project is expected to be placed in service by May 2014. The scrubber equipment upgrade will be completed during a scheduled plant maintenance outage. The scrubber waste material handling portion of the project is expected to be placed in service by March 2013. Installation of the scrubber waste handling portion of the project will be completed while the plant is in service, and will not require an extended plant maintenance outage for tie-in.

However, costs associated with the scrubber reagent preparation system upgrade portion of the project ARE included in the revenue requirement into this case as this portion of the project is expected to be placed in service by March 2012. The reagent preparation portion of this project is being constructed concurrently with the Hunter Unit 2 reagent preparation system to benefit from installation and operational costs synergies achieved through the use of common facilities between the two units. The capital investment associated with the portion of the project being placed in service during the test period is approximately $19 million. Installation of the reagent preparation system upgrade will be completed while the plant is in service, and will not require an extended plant maintenance outage for tie-in.

Q. Please describe the other major pollution control projects and associated equipment contemplated in this case.

A. The other major pollution control projects to be placed in service during the test period include:

(1) the Naughton Unit 2 low NO_X burners installation project;

(2) the Naughton Unit 1 low NO_X burners installation project;

(3) the Wyodak low NO_X burners installation project;

(4) the Huntington Unit 1 low NO_X burners installation project;

(5) Hunter Unit 2 low NO_X burners installation project; and

(6) the Jim Bridger Unit 3 scrubber upgrade project.

The Jim Bridger Unit 3 scrubber upgrade will replace internal scrubber parts (trays, piping and nozzles). This work will improve sulfur dioxide removal efficiency while enabling the bypass dampers to bypass less flue gas. The low NO_X burners projects referenced above will install new burners that utilize improved combustion characteristics and a separated over-fire air supply to the boiler to reduce NO_X emissions.

Q. Does Jim Bridger Unit 3 currently have a scrubber?

A. Yes. The scrubber project primarily includes the upgrade and replacement of existing pumps, spray headers, trays, induced draft fans, and ancillary equipment to improve the control of SO_2 emissions from the affected units.

Q. Please describe the emissions improvements that will be achieved with the pollution control projects described above.

A. The pollution control equipment investments described above are required by the permit terms and conditions issued in response to the environmental requirements described herein and support the Company's ongoing commitment to reduce SO_2 emissions from the Company's generation fleet by approximately 50 percent compared to 2005 levels. In addition to reducing SO_2 emissions, the projects support the Company's ongoing commitment to reduce NO_X emissions from the Company's generation fleet by approximately 40 percent compared to 2005 levels. These projects also meet the requirements of the Utah regional haze requirements and the Wyoming best available retrofit technology permits issued by the respective state agencies, which are intended to improve the visibility in certain national parks and wilderness areas. The emission reductions that result from these projects have been incorporated into the approved operating permits for the subject units.

Q. Have the costs of the projects been prudently managed by the Company?

A. Yes. The scrubber and bag house projects described above have been contracted under lump-sum, turnkey, engineer, procure and construct ("EPC") contract terms which resulted from competitive bidding processes. The burner replacement projects have been contracted under multiple lump-sum contracts which resulted from competitive bidding processes or job-specific work releases under established service level agreement rate structures. PacifiCorp management continues to provide oversight of the projects and closely manages any project execution plan changes or potential contract scope changes.

Q. Are there additional operating costs that will be incurred as a result of the installation of the pollution control equipment?

A. Yes. Unfortunately, but unavoidably, the operation of the new pollution control equipment will result in increased operation and maintenance costs associated with reagent, waste disposal, and equipment maintenance. These costs are summarized in Mr. Steven R. McDougal's direct testimony.

Q. How are the pollution control investment costs and associated operating costs being treated in the revenue requirement?

A. The costs for the pollution control equipment have been included in this case as explained in the revenue requirement testimony of Mr. McDougal.

Description of Generation Plant Turbine Upgrade Investments

Q. Please describe the turbine upgrade projects.

A. The turbine upgrade projects that will be placed in service during the test period include:

(1) the Huntington Unit 1 high pressure (HP)/intermediate pressure (IP)/low pressure (LP) turbine sections replacement,

(2) the Hunter Unit 2 HP/IP/LP turbine sections replacement,

(3) the Hunter Unit 3 HP/IP/LP turbine sections replacement, and

(4) the Jim Bridger Unit 1 HP/IP turbine sections replacement.

The revenue requirement impact of these investments has been included in Mr. McDougal's direct testimony.

Q. Please describe the efficiency improvements that will be achieved with the turbine upgrade projects described above.

A. The Company expects the Huntington Unit 1 turbine upgrade to allow more efficient turbine performance without increasing emissions, such that an additional 18 megawatts of capacity can to be generated by the unit. The same principles apply to the Hunter Unit 2 turbine upgrade, which is expected to provide efficiency improvements, without increasing emissions, resulting in an additional 10 megawatts of capacity to be generated by the unit. Applying the same principals, the Hunter Unit 3 turbine upgrade is expected to result in an additional 19 megawatts, and the Jim Bridger 1 turbine upgrade is expected to result in an additional 4 megawatts. Mr. Gregory Duvall has included the net power cost impact associated with these projects in his direct testimony.

Q. What is the basis for justification of these investments?

A. As part of the Company's efforts to meet the growing demand for generation, and given the advancing technological improvements in steam turbine design and manufacturing, the Company has initiated a turbine upgrade initiative. This turbine upgrade initiative will further enhance PacifiCorp's overall generation capability and cycle efficiency for the large thermal units being provided with this equipment

Description of Other Generation Plant Investments

Q. What other generation plant capital investments are included in this application?

A. Generation plant repair and replacement investments and a coal unloading facility addition at the Hayden power plant are the remaining projects included in this case. The repair and replacement projects fall primarily within three major categories: (i) boiler section replacements; (ii) control system upgrades; and (iii) other. The revenue requirement impact of these investments has been included in Mr. McDougal's direct testimony.

Q. How will customers benefit from the repair and replacement capital expenditures contemplated in this case?

A. These capital expenditures enable the Company to maintain safe, reliable, and cost-effective operation of an aging generation fleet. The Company's plants produce energy at costs lower than market prices, enabling the Company to serve its customers at some of the lowest retail electricity prices in the United States. Prudent investment in the Company's existing generating units increases the probability of continued safe and reliable operation of these low-cost resources.

Q. Please describe the Wyodak air cooled condenser replacement project.

A. The Wyodak air cooled condenser (ACC) has been in service for 33 years and has reached its end of useful life. This replacement project will replace all of the

ACC's tube bundles and headers, both of which are experiencing failures. Failed tubes and welds are allowing air in-leakage to the ACC which increases turbine backpressure, allows for accelerated corrosion of the carbon steel tubes and headers in the ACC, and results in freeze/thaw damage during cold weather operation. The project is planned to be placed in service by May 2011 and is expected to cost approximately $22 million.

Q. How will customers benefit from the Wyodak air cooled condenser replacement project?

A. The Wyodak air cooled condenser replacement project is expected to result in improved unit reliability and efficiency. From a unit reliability perspective, continued operation of the ACC in its current condition has a high potential of causing progressively more unit outages and/or derates. From a unit efficiency perspective, during the winter months it is typical for the Wyodak plant to increase turbine back pressure to ensure that the ACC does not freeze. During the summer months, poor ACC performance also causes the plant to run with high turbine back pressure. Increasing unit back pressure leads to increased fuel consumption for given megawatt output. By proceeding with the ACC replacement project, customers will benefit from improvements in the areas discussed above as well as advancements in currently available ACC technology. Technology improvements have resulted in increased equipment efficiency without increasing the size of the ACC structure. This efficiency improvement comes without increasing the power consumption of the existing cooling fans.

Q. Please describe the Hayden power plant coal unloading facility project.

A. Currently, the Hayden plant can only receive coal which is shipped by truck. The new coal unloading facility will allow the Hayden plant to also receive coal that is shipped by rail. The project includes construction of a new rail spur and loop, bridges, unloading hopper, belts, transfer points, feeders, crushers and other equipment. The project is expected to be ready for service in October 2011, at a total loaded cost of approximately $12 million (PacifiCorp share).

Q. How will customers benefit from the Hayden power plant coal unloading capital expenditure?

A. Hayden Units 1 and 2 currently consume coal produced at Peabody Energy's Twentymile mine. This coal is transported to the plant by truck over county roads. The current contract with Peabody to supply coal for Hayden expires at the end of 2011. In order to ensure a reliable, long-term supply of low-cost fuel to the plant after expiration of the Peabody contract, Hayden's owners (Public Service Company of Colorado, Salt River Project Agricultural Improvement and Power District, and PacifiCorp) requested bids from a number of regional mines that have capability to supply suitable coal to Hayden. Many of these regional mines are located too far from the Hayden plant to economically deliver coal to the facility by truck. Construction of the rail unloading facility allows these suppliers to ship coal to the plant at economic rates and to compete effectively with nearby suppliers. Ratepayers will benefit from the continued supply of cost-effective fuel to the plant.

Description of Hydro Investments

Q. What hydro plant capital investments are included in this application?

A. The hydro plant regulatory and new infrastructure investments contemplated in this case are primarily associated with new license implementation measures for the North Umpqua Hydroelectric Project; Federal Energy Regulatory Commission No. 1927 issued November 18, 2003. The revenue requirement impact of these investments has been included in Mr. McDougal's direct testimony.

Q. Please describe the Soda Springs fish passage project.

A. The Company's investment in the Soda Springs fish passage project is driven by Settlement Agreement Sections 4.1.1 and 4.1.2 of the referenced FERC license. The project will provide for the upstream and downstream volitional passage of anadromous fish by the addition of a fish ladder, fish screens and a fish observation/monitoring station. The facilities will provide for approximately six miles of additional spawning and rearing habitat. The project is planned to be placed in service by January 2012 and is expected to cost approximately $65 million.

Q. Please describe the Lemolo Unit 2 reach pipe project.

A. The Company's investment in the Lemolo Unit 2 reach pipe project is driven by Settlement Agreement Section 6.1 of the referenced FERC license. These new facilities will collect the outflow from the Lemolo 2 plant and transport the water to Toketee Lake. The purpose of the project is to prevent significant increases and decreases in the flow levels in the Umpqua River downstream of the plant which could have detrimental impacts on the native fishery. The project is planned to be placed into service in December 2011 and is expected to cost approximately $15 million.

Q. What is the basis for justification of these investments?

A. The Soda Springs hydroelectric project with a nameplate rating of 11 megawatts and the Lemolo 2 hydroelectric project with a nameplate rating of 33 megawatts are part of the eight project development comprising the North Umpqua Hydroelectric Project. The economic evaluation for the entire development was conducted in association with the Federal Energy Regulatory Commission re-licensing process prior to the issuance of the current 2003 license. The analysis indicated that the 35-year license would provide energy for customers at rates substantially lower than market prices.

Customer Benefits

Q. How will customers benefit from these capital expenditures?

A. The capital expenditures described above and otherwise included in this case enable the Company to maintain safe, reliable, and cost-effective operation of an aging generation fleet. The Company's plants produce energy at costs lower than market prices, enabling the Company to serve its customers at some of the lowest retail electricity prices in the United States. Prudent investment in the Company's existing generating units increases the probability of continued safe and reliable operation of these low-cost resources.

Description of Other Incremental O&M Costs

Q. Are there incremental O&M costs contemplated in this case associated with recently completed wind projects?

A. Yes. Incremental O&M costs for the Company's recently completed wind projects are included in this case. The High Plains and McFadden Ridge I wind projects achieved commercial operation during September 2009, and the Dunlap wind project achieved commercial operation on October 1, 2010. The incremental O&M costs included in this case are known and measurable costs associated with ongoing operation of the facilities, including labor, contracts, parts, and consumables. These costs are summarized in Mr. McDougal's direct testimony.

Q. Are there incremental O&M reductions contemplated in this case associated with the decommissioning of the Little Mountain facility?

A. Yes. In March 2010, the Company was informed that the one customer served by the Little Mountain substation has chosen to construct its own 138 kV substation instead of continuing to receive service from the Company due to a better price opportunity. Without this customer connection, further investment in the deteriorating Little Mountain substation and continued operation of the Little Mountain generation facility are no longer in the best interest of customers. As such, the Company's Little Mountain facility is currently expected to be retired and decommissioned in 2012. Planned decommissioning of the facility will result in an incremental decrease in O&M costs contemplated in this case of approximately $0.9 million. These costs are summarized in Mr. McDougal's direct testimony.

Q. Are there incremental O&M costs contemplated in this case associated with the Lake Side facility?

A. Yes. In 2004, as part of the Lake Side 1 resource addition, the Company entered into a Long Term Program ("LTP") maintenance contract with Siemens Energy, Inc., ("Siemens") to provide parts and services to cover planned maintenance of the two Siemens combustion turbines installed on that project over 100,000 equivalent base hours ("EBH") or 3,600 equivalent starts ("ES"). The scope of the contract included combustion inspections, hot gas path inspections, and major inspections of the covered equipment. In November 2010, the Company executed an amended and restated LTP maintenance contract with Siemens, significantly amending and extending the scope, commercial terms, and duration of the managed long term parts and services program contract for the Lake Side 1 combined-cycle natural gas plant. Key changes to the LTP maintenance contract include extension of the term of the contract by an additional 50,000 EBH, or 1,800 ES; upgraded combustion turbine hardware; upgrades to the two combustion turbine generators; improved terms and conditions regarding warranty and indemnification; availability of two replacement combustion turbine rotor assemblies at the 100,000 EBH overhauls; and associated inspection intervals. The primary benefits expected to be realized from the amended and restated LTP maintenance contract include increased availability of the equipment associated with modified outage schedules; decreased outage duration at 100,000 EBH due to availability of combustion turbine rotor assemblies; avoided parts purchases and repair costs to self-perform services from 100,000 EBH to 150,000 EBH; and improved indemnity and warranty coverage.

Incremental costs of approximately $1.2 million associated with said amended and restated LTP maintenance contract are incorporated in this case. These costs are summarized in Mr. McDougal's direct testimony.

Q. Are there incremental O&M costs contemplated in this case associated with operation of the Cholla Unit 4 power plant?

A. Yes. The mine which historically supplied cost-effective coal to Cholla Unit 4 was completely mined out in early 2010. While also cost-effective, the new fuel being supplied to the facility contains more sulfur and ash, and is more abrasive. In order to continue to comply with environmental requirements while burning the new fuel, a new scrubber and bag house were installed on the unit in 2008. The new high-removal-rate scrubber and the higher sulfur coal have combined to raise limestone consumption significantly. Also, the abrasive nature of the new fuel has raised costs for pulverizer and boiler maintenance in the plant. Even with these changes, Cholla Unit 4 continues to provide essential energy and system regulation benefits to PacifiCorp's electric system at an attractive price. Incremental costs of approximately $2.3 million associated with the operational changes described above are included in this case. These costs are summarized in Mr. McDougal's direct testimony.

Conclusion

Q. Please summarize your testimony.

A. Investments in pollution control equipment are required to meet the Regional Haze rules, enacted in 2005 by the EPA, and the resulting BART reviews, state implementation plans, and permitting processes. The investment in pollution control equipment included in this case would not change if additional environmental requirements are imposed in the future, including restrictions upon carbon dioxide emissions. The investment allows for the continued operation of low-cost coal-fired generation facilities, while achieving significant environmental improvements to air quality and regional haze issues.

The Company is also making other prudent capital expenditures in its existing generation fleet, including hydro, which will benefit customers by maintaining safe, reliable, efficient, cost-effective generating resources and production facilities. The capital investments included in this case are reasonable and prudent, and the Company should be granted full cost recovery for these investments.

The Company continues to prudently manage O&M costs. The Company should be granted full recovery of the incremental O&M costs contemplated in this case.

Q. Does this conclude your direct testimony?

A. Yes.